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EXAMINER	
HENSON, MISCHITA L	
ART UNIT	PAPER NUMBER
2857	
NOTIFICATION DATE	DELIVERY MODE
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Please find below and/or attached an Office communication concerning this application or proceeding.

The time period for reply, if any, is set in the attached communication.

Notice of the Office communication was sent electronically on above-indicated "Notification Date" to the following e-mail address(es):

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Office Action Summary	Application No.	Applicant(s)	
	10/813,698	CRAIG, DAVID P.	
	Examiner	**Art Unit**	
	Mi'schita' Henson	2857	

-- The MAILING DATE of this communication appears on the cover sheet with the correspondence address --

Period for Reply

A SHORTENED STATUTORY PERIOD FOR REPLY IS SET TO EXPIRE *3* MONTH(S) OR THIRTY (30) DAYS, WHICHEVER IS LONGER, FROM THE MAILING DATE OF THIS COMMUNICATION.

- Extensions of time may be available under the provisions of 37 CFR 1.136(a). In no event, however, may a reply be timely filed after SIX (6) MONTHS from the mailing date of this communication.
- If NO period for reply is specified above, the maximum statutory period will apply and will expire SIX (6) MONTHS from the mailing date of this communication.
- Failure to reply within the set or extended period for reply will, by statute, cause the application to become ABANDONED (35 U.S.C. § 133). Any reply received by the Office later than three months after the mailing date of this communication, even if timely filed, may reduce any earned patent term adjustment. See 37 CFR 1.704(b).

Status

1)☒ Responsive to communication(s) filed on *12 November 2009*.

2a)☒ This action is **FINAL**. 2b)☐ This action is non-final.

3)☐ Since this application is in condition for allowance except for formal matters, prosecution as to the merits is closed in accordance with the practice under *Ex parte Quayle*, 1935 C.D. 11, 453 O.G. 213.

Disposition of Claims

4)☒ Claim(s) *1-30* is/are pending in the application.

4a) Of the above claim(s) _____ is/are withdrawn from consideration.

5)☐ Claim(s) _____ is/are allowed.

6)☒ Claim(s) *1-3,7-18 and 22-30* is/are rejected.

7)☒ Claim(s) *4-6 and 19-21* is/are objected to.

8)☐ Claim(s) _____ are subject to restriction and/or election requirement.

Application Papers

9)☐ The specification is objected to by the Examiner.

10)☒ The drawing(s) filed on *30 March 2004* is/are: a)☒ accepted or b)☐ objected to by the Examiner.

Applicant may not request that any objection to the drawing(s) be held in abeyance. See 37 CFR 1.85(a).

Replacement drawing sheet(s) including the correction is required if the drawing(s) is objected to. See 37 CFR 1.121(d).

11)☐ The oath or declaration is objected to by the Examiner. Note the attached Office Action or form PTO-152.

Priority under 35 U.S.C. § 119

12)☐ Acknowledgment is made of a claim for foreign priority under 35 U.S.C. § 119(a)-(d) or (f).

a)☐ All b)☐ Some * c)☐ None of:

1.☐ Certified copies of the priority documents have been received.

2.☐ Certified copies of the priority documents have been received in Application No. _____.

3.☐ Copies of the certified copies of the priority documents have been received in this National Stage application from the International Bureau (PCT Rule 17.2(a)).

* See the attached detailed Office action for a list of the certified copies not received.

Attachment(s)

1) ☐ Notice of References Cited (PTO-892)

2) ☐ Notice of Draftsperson's Patent Drawing Review (PTO-948)

3) ☐ Information Disclosure Statement(s) (PTO/SB/08) Paper No(s)/Mail Date _____.

4) ☐ Interview Summary (PTO-413) Paper No(s)/Mail Date. _____ .

5) ☐ Notice of Informal Patent Application

6) ☐ Other: _____.

DETAILED ACTION

This action is responsive to the amendment filed November 12, 2009. Claims 11 and 26 have been amended. Claims 1-30 are pending.

Claim Rejections - 35 USC § 103

The following is a quotation of 35 U.S.C. 103(a) which forms the basis for all obviousness rejections set forth in this Office action:

> (a) A patent may not be obtained though the invention is not identically disclosed or described as set forth in section 102 of this title, if the differences between the subject matter sought to be patented and the prior art are such that the subject matter as a whole would have been obvious at the time the invention was made to a person having ordinary skill in the art to which said subject matter pertains. Patentability shall not be negatived by the manner in which the invention was made.

1. Claims 1-3, 7-9, 13-18, 22-24 and 28-30 are rejected under 35 U.S.C. 103(a) as being unpatentable over Patzek et al. in US Patent 6,904,366, in view of Engler et al. in NPL "Analysis of pressure and pressure derivative without type curve matching, 4. Naturally fractured reservoirs".

Regarding claim 1, Patzek et al. teaches:

A method of detecting a fracture with residual width from a previous well treatment during a well fracturing operation in a subterranean formation containing a reservoir fluid (see waterflooding, column 1 lines 29-55), comprising the steps of:

(a) injecting an injection fluid into the formation at an injection pressure exceeding the formation fracture pressure (see "injecting water or other fluids", column 1 liens 32-34; see also "excess injector pressure is used…" (i.e. exceeding the formation fracture pressure), column 1 lines 45-50; see also water injection, column 5 lines 28-33);

(b) gathering pressure measurement data from the formation during the injection

and a subsequent shut-in period (see “a time measurement device, a pressure measurement device…”, column 2 lines 54-55; see also column 2 lines 10-17; see also MEMS sensors, column 5 lines 60-63; see also column 6 lines 35-36);

(c) transforming the pressure measurement data into a constant rate equivalent pressure (see “variable injection pressure and transformed it to an equivalent simpler form”, column 20 lines 20-33 (an equivalent simpler form is interpreted to be a constant rate equivalent pressure);

Patzek et al. differs from the claimed invention in that it does not explicitly teach (d) detecting the presence of a dual unit-slope wellbore storage in the transformed pressure measurement data, said dual unit-slope being indicative of the presence of a fracture retaining residual width.

Engler et al. teaches direct synthesis for interpreting pressure transient tests in naturally fractured reservoirs that includes the effect of the wellbore storage (Abstract). Further, Engler et al. teaches “the method combines the characteristic points and slopes from a log-log plot of pressure and pressure derivative data with the exact, analytically solution to obtain reservoir properties. It has been successfully applied to…homogenous reservoirs with skin and wellbore storage…vertically fractured wells…” (i.e. detecting the presence of a dual unit-slope wellbore storage in the transformed pressure measurement data, said dual unit-slope being indicative of the presence of a fracture retaining residual width, Background par. 4, see Step-by-step procedures *Step 3, Step 8* and *Solution* par. 1, and Fig. 10).

It would have been obvious to one of ordinary skill in the art at the time the

invention was made to have combined the teachings of Engler et al. with Patzek et al. because Engler et al. teaches the direct synthesis method that offers consistent and accurate results from pressure tests with or without all reservoir flow regimes (Abstract), thereby improving the accuracy and reliability of the system.

Regarding claim 2, Patzek et al. and Engler et al. teach the limitations of claim 1 as indicated above. Further, Patzek et al. teaches:

The method of claim 1 wherein the time of injection is limited to the time required for the reservoir fluid to exhibit pseudoradial flow (see pseudo-radial, column 10 lines 25-30).

Regarding claim 3, Patzek et al. and Engler et al. teach the limitations of claim 1 as indicated above. Further, Patzek et al. teaches:

The method of claim 1 wherein the reservoir fluid is compressible (see reservoir filled with a slightly compressible fluid, column 11 lines 11-15); and

the transformation of pressure measurement data is based on the properties of the compressible fluid contained in the reservoir (see “variable injection pressure and transformed it to an equivalent simpler form”, column 20 lines 20-33).

Regarding claim 7, Patzek et al. and Engler et al. teach the limitations of claim 3 as indicated above. Further, Patzek et al. teaches:

The method of claim 3 wherein the injection fluid is slightly compressible and contains desirable additives for compatibility with said formation (see fluid, especially emulsions and mixtures, column 6 lines 3-8; see also slightly compressible injection fluid, column 36, lines 23-27).

Regarding claim 8, Patzek et al. and Engler et al. teach the limitations of claim 3 as indicated above. Further, Patzek et al. teaches:

The method of claim 3 wherein the injection fluid is compressible and contains desirable additives for compatibility with said formation (see fluid, especially emulsions and mixtures, column 6 lines 3-8; see also compressible injection fluid, column 36, lines 23-27).

Regarding claim 9, Patzek et al. and Engler et al. teach the limitations of claim 1 as indicated above. Further, Patzek et al. teaches:

The method of claim 1 wherein the reservoir fluid is slightly compressible (see reservoir filled with a slightly compressible fluid, column 11 lines 11-15); and

the transformation of pressure measurement data is based on the properties of the slightly compressible fluid contained in the reservoir (see “variable injection pressure and transformed it to an equivalent simpler form”, column 20 lines 20-33).

Regarding claim 13, Patzek et al. and Engler et al. teach the limitations of claim 9 as indicated above. Further, Patzek et al. teaches:

The method of claim 9 wherein the injection fluid is compressible and contains desirable additives for compatibility with said formation (see fluid, especially emulsions and mixtures, column 6 lines 3-8; see also compressible injection fluid, column 36, lines 23-27).

Regarding claim 14, Patzek et al. and Engler et al. teach the limitations of claim 9 as indicated above. Further, Patzek et al. teaches:

The method of claim 9 wherein the injection fluid is slightly compressible and

contains desirable additives for compatibility with said formation (see fluid, especially emulsions and mixtures, column 6 lines 3-8; see also slightly compressible injection fluid, column 36, lines 23-27).

Regarding claim 15, Patzek et al. teaches:

A system for detecting a fracture with residual width from a previous well treatment during a well fracturing operation in a subterranean formation containing a reservoir fluid, comprising:

- a pump for injecting an injection fluid at an injection pressure exceeding the formation fracture pressure (means for pumping water is interpreted to be a pump, see column 1 lines 49-51; see also pump pressure, column 39 lines 37-39; see also “excess injector pressure is used…” (i.e. exceeding the formation fracture pressure), column 1 lines 45-50)

- means for gathering pressure measurement data in the wellbore at various points in time during the injection and a subsequent shut-in period (see “a time measurement device, a pressure measurement device…”, column 2 lines 54-55; see also column 2 lines 10-17; see also MEMS sensors, column 5 lines 60-63; see also column 6 lines 35-36);

- processing means for transforming said pressure measurement data into a constant rate equivalent pressure (a computer, especially microprocessor or digital signal processor, is interpreted to be a processing means for transforming, see computer, column 4 line 65-column 5 line 7; see also “variable injection pressure and transformed it to an equivalent simpler form”, column 20 lines 20-33 (an equivalent

simpler form is interpreted to be a constant rate equivalent pressure); see also means for analyzing and manipulating, column 6 lines 19-28);

Patzek et al. differs from the claimed invention in that it does not explicitly teach means for detecting the presence of a dual unit-slope wellbore storage in the transformed pressure measurement data, said dual unit-slope being indicative of the presence of a fracture retaining residual width.

Engler et al. teaches direct synthesis for interpreting pressure transient tests in naturally fractured reservoirs that includes the effect of the wellbore storage (Abstract). Further, Engler et al. teaches "the method combines the characteristic points and slopes from a log-log plot of pressure and pressure derivative data with the exact, analytically solution to obtain reservoir properties. It has been successfully applied to…homogenous reservoirs with skin and wellbore storage…vertically fractured wells…" (the means for detecting the pressure and pressure derivative curves is interpreted to be means for detecting the presence of a dual unit-slope wellbore storage in the transformed pressure measurement data, said dual unit-slope being indicative of the presence of a fracture retaining residual width, Background par. 4, see Step-by-step procedures *Step 3, Step 8* and *Solution* par. 1, and Fig. 10).

It would have been obvious to one of ordinary skill in the art at the time the invention was made to have combined the teachings of Engler et al. with Patzek et al. because Engler et al. teaches the direct synthesis method that offers consistent and accurate results from pressure tests with or without all reservoir flow regimes (Abstract), thereby improving the accuracy and reliability of the system.

Regarding claim 16, Patzek et al. and Engler et al. teach the limitations of claim 15 as indicated above. Further, Patzek et al. teaches plotting pressure distribution data or pressure vs. time (the means for plotting is interpreted to be graphics means for plotting said transformed pressure measurement data, see for example, Figs. 2A-12).

Regarding claim 17, Patzek et al. and Engler et al. teach the limitations of claim 15 as indicated above.

The system of claim 15 wherein the time of injection is limited to the time required for the reservoir fluid to exhibit pseudoradial flow (see pseudo-radial, column 10 lines 25-30).

Regarding claim 18, Patzek et al. and Engler et al. teach the limitations of claim 15 as indicated above.

The system of claim 15 wherein the reservoir fluid is compressible (see reservoir filled with a slightly compressible fluid, column 11 lines 11-15); and

the transformation of pressure measurement data is based on the properties of the compressible fluid contained in the reservoir (see “variable injection pressure and transformed it to an equivalent simpler form”, column 20 lines 20-33).

Regarding claim 22, Patzek et al. and Engler et al. teach the limitations of claim 15 as indicated above. Further, Patzek et al. teaches:

The system of claim 15 wherein the injection fluid is compressible and contains desirable additives for compatibility with said formation (see fluid, especially emulsions and mixtures, column 6 lines 3-8; see also compressible injection fluid, column 36, lines 23-27).

Regarding claim 23, Patzek et al. and Engler et al. teach the limitations of claim 15 as indicated above. Further, Patzek et al. teaches:

The system of claim 15 wherein the injection fluid is slightly compressible and contains desirable additives for compatibility with said formation (see fluid, especially emulsions and mixtures, column 6 lines 3-8; see also slightly compressible injection fluid, column 36, lines 23-27).

Regarding claim 24, Patzek et al. and Engler et al. teach the limitations of claim 15 as indicated above. Further, Patzek et al. teaches:

The system of claim 15 wherein the reservoir fluid is slightly compressible (see reservoir filled with a slightly compressible fluid, column 11 lines 11-15); and

the transformation of pressure measurement data is based on the properties of the slightly compressible fluid contained in the reservoir (see "variable injection pressure and transformed it to an equivalent simpler form", column 20 lines 20-33).

Regarding claim 28, Patzek et al. teaches:

A system for detecting a fracture with residual width from a previous well treatment during a well fracturing operation in a subterranean formation containing a reservoir fluid, comprising:

- a pump for injecting an injection fluid at an injection pressure exceeding the formation fracture pressure (means for pumping water is interpreted to be a pump, see column 1 lines 49-51; see also pump pressure, column 39 lines 37-39; see also "excess injector pressure is used…" (i.e. exceeding the formation fracture pressure), column 1 lines 45-50)

- means for gathering pressure measurement data in the wellbore at various points in time during the injection and a subsequent shut-in period (see “a time measurement device, a pressure measurement device…”, column 2 lines 54-55; see also column 2 lines 10-17; see also MEMS sensors, column 5 lines 60-63; see also column 6 lines 35-36);

- processing means for transforming said pressure measurement data into a constant rate equivalent pressure (a computer, especially microprocessor or digital signal processor, is interpreted to be a processing means for transforming, see computer, column 4 line 65-column 5 line 7; see also “variable injection pressure and transformed it to an equivalent simpler form”, column 20 lines 20-33 (an equivalent simpler form is interpreted to be a constant rate equivalent pressure); see also means for analyzing and manipulating, column 6 lines 19-28); and

- graphics means for plotting said transformed pressure measurement data representative of before and after closure periods of wellbore storage (the means for plotting is interpreted to be graphics means for plotting said transformed pressure measurement data, see for example, Figs. 2A-12)

Patzek et al. differs from the claimed invention in that it does not explicitly teach detecting a dual unit-slope wellbore storage indicative of the presence of a fracture retaining residual width.

Engler et al. teaches direct synthesis for interpreting pressure transient tests in naturally fractured reservoirs that includes the effect of the wellbore storage (Abstract). Further, Engler et al. teaches “the method combines the characteristic points and slopes

from a log-log plot of pressure and pressure derivative data with the exact, analytically solution to obtain reservoir properties. It has been successfully applied to…homogenous reservoirs with skin and wellbore storage…vertically fractured wells…" (detecting the pressure and pressure derivative curves is interpreted to be detecting a dual unit-slope wellbore storage indicative of the presence of a fracture retaining residual width, Background par. 4, see Step-by-step procedures *Step 3, Step 8* and *Solution* par. 1, and Fig. 10).

It would have been obvious to one of ordinary skill in the art at the time the invention was made to have combined the teachings of Engler et al. with Patzek et al. because Engler et al. teaches the direct synthesis method that offers consistent and accurate results from pressure tests with or without all reservoir flow regimes (Abstract), thereby improving the accuracy and reliability of the system.

Regarding claim 29, Patzek et al. and Engler et al. teach the limitations of claim 28 as indicated above. Further, Patzek et al. teaches:

The system of claim 28 wherein

- the reservoir fluid is compressible (see reservoir filled with a slightly compressible fluid, column 11 lines 11-15);

- the injection fluid is compressible or slightly compressible and contains desirable additives for compatibility with said formation (see fluid, especially emulsions and mixtures, column 6 lines 3-8; see also slightly compressible injection fluid, column 36, lines 23-27); and

- the transformation of pressure measurement data is based on the properties of

the compressible reservoir fluid (see “variable injection pressure and transformed it to an equivalent simpler form”, column 20 lines 20-33).

Regarding claim 30, Patzek et al. and Engler et al. teach the limitations of claim 28 as indicated above. Further, Patzek et al. teaches:

The system of claim 28 wherein

- the reservoir fluid is slightly compressible (see reservoir filled with a slightly compressible fluid, column 11 lines 11-15);

- the injection fluid is compressible or slightly compressible and contains desirable additives for compatibility with said formation (see fluid, especially emulsions and mixtures, column 6 lines 3-8; see also slightly compressible injection fluid, column 36, lines 23-27); and

- the transformation of pressure measurement data is based on the properties of the slightly compressible reservoir fluid (see “variable injection pressure and transformed it to an equivalent simpler form”, column 20 lines 20-33).

2. Claims 10, 12, 25 and 27 are rejected under 35 U.S.C. 103(a) as being unpatentable over Patzek et al. in US Patent 6,904,366 and Engler et al. in NPL “Analysis of pressure and pressure derivative without type curve matching, 4. Naturally fractured reservoirs” as applied to claims 9 and 27 above, and further in view of Espinosa-Paredes et al. in NPL “Estimation of static formation temperatures in geothermal wells”.

Regarding claim 10, Patzek et al. and Engler et al. teach the limitations of claim 9 as indicated above. Further, Engler et al. teaches a pressure difference Δp (see Δp,

Step-by-step procedures *Step 1*, Notation and Fig. 10).

Patzek et al. and Engler differ from the claimed invention in that they do not necessarily teach the shut-in time relative to the end of the injection to be $\Delta t = t - t_{ne}$.

Espinosa-Paredes et al. teaches estimating geothermal well data using information obtain during drilling stoppages, after circulation stops and the well returns to thermal equilibrium wherein Δt is the time elapsed since circulation stops, also known as shut-in time (i.e. shut-in time relative to the end of the injection, see Δt, sections 2.1-2.2 on pages 1346-1348; see also Introduction, pg. 1343).

It would have been obvious to one of ordinary skill in the art at the time the invention was made to have combined the teachings of Espinosa-Paredes et al. with Patzek et al. and Engler et al. because Espinosa-Paredes et al. teaches numerical simulation of combined circulation and shut-in period in wells (Abstract), thereby increasing the accuracy of the system.

Regarding claim 12, Patzek et al., Engler et al. and Espinosa-Paredes et al. teach the limitations of claim 10 as indicated above. Further, Engler et al. teaches plotting a log-log graph of a pressure function versus time where $\Delta' p = \Delta p \Delta t$ (see Δ'p, Step-by-step procedures *Step 3* and *Solution* par. 1 and Fig. 10; see also t*dp, Fig. 10).

It would have been obvious to one of ordinary skill in the art at the time the invention was made to have combined the teachings of Espinosa-Paredes et al. with Patzek et al. and Engler et al. because Espinosa-Paredes et al. teaches numerical simulation of combined circulation and shut-in period in wells (Abstract), thereby increasing the accuracy of the system.

Regarding claim 25, Patzek et al. and Engler et al. teach the limitations of claim 24 as indicated above. Further, Engler et al. teaches a pressure difference Δp (see Δp, Step-by-step procedures *Step 1*, Notation and Fig. 10).

Patzek et al. and Engler differ from the claimed invention in that they do not necessarily teach the shut-in time relative to the end of the injection to be $\Delta t = t - t_{ne}$.

Espinosa-Paredes et al. teaches estimating geothermal well data using information obtain during drilling stoppages, after circulation stops and the well returns to thermal equilibrium wherein Δt is the time elapsed since circulation stops, also known as shut-in time (i.e. shut-in time relative to the end of the injection, see Δt, sections 2.1-2.2 on pages 1346-1348; see also Introduction, pg. 1343).

It would have been obvious to one of ordinary skill in the art at the time the invention was made to have combined the teachings of Espinosa-Paredes et al. with Patzek et al. and Engler et al. because Espinosa-Paredes et al. teaches numerical simulation of combined circulation and shut-in period in wells (Abstract), thereby increasing the accuracy of the system.

Regarding claim 27, Patzek et al., Engler et al. and Espinosa-Paredes et al. teach the limitations of claim 25 as indicated above. Further, Engler et al. teaches plotting a log-log graph of a pressure function versus time where $\Delta' p = \Delta p \Delta t$ (see $\Delta' p$, Step-by-step procedures *Step 3* and *Solution* par. 1 and Fig. 10; see also t*dp, Fig. 10).

It would have been obvious to one of ordinary skill in the art at the time the invention was made to have combined the teachings of Espinosa-Paredes et al. with Patzek et al. and Engler et al. because Espinosa-Paredes et al. teaches numerical

simulation of combined circulation and shut-in period in wells (Abstract), thereby increasing the accuracy of the system.

Allowable Subject Matter

3. Claims 4-6 and 19-21 are objected to as being dependent upon a rejected base claim, but would be allowable if rewritten in independent form including all of the limitations of the base claim and any intervening claims.

Response to Arguments

4. Applicant's arguments filed November 12, 2009 have been fully considered but they are not persuasive.

Applicant argues:

> The Examiner acknowledges that Patzek fails to disclose detecting the presence of a dual unit-slope wellbore storage in the transformed pressure measurement data and relies on Engler as teaching that limitation. Office Action, at 4. However, the combination of Patzek and Engler fails to teach or suggest "injecting an injection fluid into the formation at an injection pressure exceeding the formation fracture pressure," "transforming the pressure measurement data into a constant rate equivalent pressure" and "detecting the presence of a dual unit-slope wellbore storage in the transformed pressure measurement data" as recited by independent claims 1, 15 and 28…
>
> Moreover, Engler fails to disclose that which Patzek lacks. Engler is directed to a direct synthesis method for interpreting pressure transient tests in naturally fractured reservoirs. Engler, Abstract. Applicant does not find a teaching of the missing elements of Patzek in Engler. Rather, the Office Action merely relies on the secondary reference for its alleged teaching of "detecting the presence of a dual unit-slope wellbore storage in the transformed pressure measurement data, said dual unit slope being indicative of the presence of a fracture retaining residual width." Moreover, Engler does not disclose that variable storage can occur. Nor does Engler disclose how a closing fracture and residual fracture width contribute to variable storage. Accordingly, the combination of Patzek and Engler fails to establish that every limitation of independent claims 1, 15 and 28 was known in the prior art.

Patzek et al. teaches "a system of wells ***injecting water or other fluids***…When ***excess injector pressure is used***, the geological strata (or layer) containing the oil can

be crushed (or hydrofractured)…" (emphasis added, see "injecting water or other fluids", column 1 liens 32-34; see also "excess injector pressure is used…" (i.e. exceeding the formation fracture pressure), column 1 lines 45-50; see also water injection, column 5 lines 28-33); Examiner interprets "injecting water or other fluids" to be "injecting an injection fluid into the formation" and "excess injector pressure is used" to be "pressure exceeding the formation fracture pressure" and therefore, as the claims are presented, Patzek et al. teaches the claimed limitation "injecting an injection fluid into the formation at an injection pressure exceeding the formation fracture pressure". Without concurrence with Applicant's assertion that "the Carter's model has been transformed into an equivalent simpler form", The Examiner notes that the Carter's model admits "variable injection pressure" and therefore when the model is transformed the "variable injection pressure" would inherently be transformed thus Patzek et al. teaches "transforming the pressure measurement data into a constant rate equivalent pressure".

Patzek et al. was not relied upon to teach "detecting the presence of a dual unit-slope wellbore storage in the transformed pressure measurement data, said dual unit-slope being indicative of the presence of a fracture retaining residual width".

In response to applicant's argument that the references fail to show certain features of applicant's invention, it is noted that the features upon which applicant relies (i.e., "variable storage can occur") are not recited in the rejected claim(s). Although the claims are interpreted in light of the specification, limitations from the specification are not read into the claims. See *In re Van Geuns*, 988 F.2d 1181, 26 USPQ2d 1057 (Fed. Cir. 1993).

Applicant's specification discloses "Figure 3 is a first *log-log graph* of the transformed fracture injection/falloff test shut-in pressure data, such as *adjusted pressure and adjusted pressure derivative, showing a dual unit slope wellbore* storage and indicating a fracture retaining residual width" (emphasis added, [0029] and Fig. 3). As stated above, Engler et al. teaches direct synthesis for interpreting pressure transient tests in naturally fractured reservoirs that includes the effect of the wellbore storage (Abstract). Further, Engler et al. teaches "the method combines the characteristic points and slopes from ***a log-log plot of pressure and pressure derivative data with the exact***, analytically solution to obtain reservoir properties. It has been successfully applied to…homogenous reservoirs with skin and ***wellbore storage***…vertically fractured wells…" (emphasis added, i.e. detecting the presence of a dual unit-slope wellbore storage in the transformed pressure measurement data, said dual unit-slope being indicative of the presence of a fracture retaining residual width, Background par. 4, see Step-by-step procedures *Step 3, Step 8* and *Solution* par. 1, and ***Fig. 10***). It would have been obvious to one of ordinary skill in the art at the time the invention was made to have combined the teachings of Engler et al. with Patzek et al. because Engler et al. teaches the direct synthesis method that offers consistent and accurate results from pressure tests with or without all reservoir flow regimes (Abstract), thereby improving the accuracy and reliability of the system.

Therefore, the Examiner maintains that the combination of Patzek et al. and Engler establishes that every limitation of independent claims 1,15 and 23 was known in the prior art.

Applicant argues:

> Claims 10 and 12 depend from independent claim 1 and claims 25 and 27 depend from independent claim 15. As discussed above, Patzek and Engler fail to disclose all limitations of independent claims 1 and 15. Espinosa-Paredes fails to disclose that which Patzek and Engler lack. Specifically, Espinosa-Paredes is directed to an analysis of temperatures in geothermal wells. Espinosa-Paredes, Title & Abstract. The Applicant does not find a teaching of "injecting an injection fluid into the formation at an injection pressure exceeding the formation fracture pressure," "transforming the pressure measurement data into a constant rate equivalent pressure" and "detecting the presence of a dual unit-slope wellbore storage in the transformed pressure measurement data" in Espinosa-Paredes as recited in independent claims 1 and 15.

The Examiner notes that the Espinosa-Paredes reference was not relied upon to teach said limitations. See above.

Conclusion

5. **THIS ACTION IS MADE FINAL.** Applicant is reminded of the extension of time policy as set forth in 37 CFR 1.136(a).

A shortened statutory period for reply to this final action is set to expire THREE MONTHS from the mailing date of this action. In the event a first reply is filed within TWO MONTHS of the mailing date of this final action and the advisory action is not mailed until after the end of the THREE-MONTH shortened statutory period, then the shortened statutory period will expire on the date the advisory action is mailed, and any extension fee pursuant to 37 CFR 1.136(a) will be calculated from the mailing date of the advisory action. In no event, however, will the statutory period for reply expire later than SIX MONTHS from the mailing date of this final action.

6. Any inquiry concerning this communication or earlier communications from the examiner should be directed to Mi'schita' Henson whose telephone number is (571) 270-3944. The examiner can normally be reached on Monday - Thursday 7:30 a.m. -

4:00 p.m. EST.

If attempts to reach the examiner by telephone are unsuccessful, the examiner's supervisor, Eliseo Ramos-Feliciano can be reached on (571) 272-7925. The fax phone number for the organization where this application or proceeding is assigned is 571-273-8300.

Information regarding the status of an application may be obtained from the Patent Application Information Retrieval (PAIR) system. Status information for published applications may be obtained from either Private PAIR or Public PAIR. Status information for unpublished applications is available through Private PAIR only. For more information about the PAIR system, see http://pair-direct.uspto.gov. Should you have questions on access to the Private PAIR system, contact the Electronic Business Center (EBC) at 866-217-9197 (toll-free). If you would like assistance from a USPTO Customer Service Representative or access to the automated information system, call 800-786-9199 (IN USA OR CANADA) or 571-272-1000.

01/28/2010
/Mi'schita' Henson/
Examiner, Art Unit 2857

/Eliseo Ramos-Feliciano/
Supervisory Patent Examiner, Art Unit 2857